UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
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ATLANTA, GEORGIA 30303-8931

January 30, 2007

Carolina Power and Light Company
ATTN: Mr. James Scarola
Vice President
Brunswick Steam Electric Plant
P. O. Box 10429
Southport, NC 28461

SUBJECT: BRUNSWICK STEAM ELECTRIC PLANT - NRC INTEGRATED INSPECTION REPORT NOS. 05000324/2006005 AND 05000325/2006005

Dear Mr. Scarola:

On December 31, 2006, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Brunswick Units 1 and 2 facilities. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 19, 2007, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

As an incentive to encourage licensee participation in the International Atomic Energy Agency Operational Safety Review Team (OSART) Missions, the NRC determined that, for those NRC baseline inspections that overlap, either in part or fully, with an OSART review, a one-time regulatory credit (reduction in baseline inspection program), would be granted. Based on a review of the inspection report from an OSART inspection conducted at Brunswick in May, 2005, the NRC determined that Brunswick qualified for a 25% reduction of the inspection effort for two NRC inspection procedures (IPs) documented in the enclosed report. Specifically, credit was given for IP 71111.05Q, Fire Protection, and IP 71111.22, Surveillance Testing. As such, the scope of the inspection of these procedures was reduced by 25%.

This report documents one self-revealing finding and one NRC-identified finding both of very low safety significance (Green). The findings were determined to involve violations of NRC requirements. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs), in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you contest these non-cited violations, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Brunswick Steam Electric Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Randall A. Musser, Chief
Reactor Projects Branch 4
Division of Reactor Projects

Docket Nos.: 50-325, 50-324
License Nos: DPR-71, DPR-62

Enclosure: Inspection Report 05000325, 324/2006005
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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REGION II

Docket Nos:	50-325, 50-324
License Nos:	DPR-71, DPR-62
Report Nos:	05000325/2006005 and 05000324/2006005
Licensee:	Carolina Power and Light (CP&L)
Facility:	Brunswick Steam Electric Plant, Units 1 & 2
Location:	8470 River Road SE Southport, NC 28461
Dates:	October 1, 2006 through December 31, 2006
Inspectors:	E. DiPaolo, Senior Resident Inspector J. Austin, Resident Inspector R. Aiello, Senior Operations Engineer (Section 1R11.2) M. Bates, Senior Operations Engineer (Section 1R11.2) F. Ehrhardt, Operations Engineer (Section 1R11.3)
Approved by:	Randall A. Musser, Chief Reactor Projects Branch 4 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000325/2006005, 05000324/2006005; 10/01/06 - 12/31/06; Brunswick Steam Electric Plant, Units 1 and 2; Maintenance Effectiveness and Surveillance Testing.

The report covered a 3-month period of inspection by resident inspectors, two senior operations engineers, and one operations engineer. Two Green non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing non-cited violation of Technical Specification 5.4.1, Administrative Controls (Procedures), was identified for failing to follow the work management process for the performance of minor maintenance. Minor maintenance was performed on a Unit 1 instrument air isolation valve to a control rod hydraulic control unit without obtaining senior reactor operator approval. During the maintenance, the valve was inadvertently closed which isolated air to the hydraulic control unit and the associated control rod scrammed. As a result, control room operators were challenged by the reactivity event and subsequent power maneuvers to restore the control rod to the proper position. This issue was entered into the corrective action program for resolution.

  The finding was more than minor because it is associated with equipment performance and affected the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. This finding is of very low safety significance because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigating equipment or functions would not be available. This finding had a crosscutting aspect of Human Performance because the control of the work did not keep operations personnel apprised of work status or the potential operational impact of the work activities (Section 1R12.2).

Cornerstone: Mitigating Systems

- Green. An NRC-identified non-cited violation of 10CFR50, Appendix B, Criteria XII, Control of Measuring and Test Equipment, was identified for failing to periodically calibrate the Units 1 and 2 service water pump discharge pressure gages. As a result, the quality of the test data collected from the gages, used to satisfy ASME Section XI in-service test requirements and performed to demonstrate pump operability, was compromised. This issue was entered into the corrective action program for resolution.

The finding was more than minor because it was associated with service water pump equipment performance and affected the Mitigating System Cornerstone objective to ensure the capability of system that respond to initiating events to prevent undesirable consequences. In addition, if left uncorrected the finding could potentially become a more significant safety concern because the issue affected all the site's service water pumps and degraded pump performance could go undetected. The finding was determined to be of very low safety significance (Green) because it did not result in the loss of safety function of a service water pump (Section 1R22.2).

B. Licensee Identified Violations

A violation of very low safety significance, which was identified by the licensee, has been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. The violation is listed in Section 4OA7.

REPORT DETAILS

Summary of Plant Status

Unit 1

Unit 1 began the inspection period operating at full power. On November 2, a reactor shutdown was commenced in accordance with Technical Specifications due to one required offsite power source (Unit 2 startup auxiliary transformer) and emergency diesel generator (EDG) #1 being inoperable. The shutdown was secured on November 3 with power at approximately 81 percent when the Unit 2 startup auxiliary transformer was restored to an operable status. Full power was achieved later that day. On November 20, a planned downpower was performed to 53 percent to facilitate main turbine valve testing, main steam isolation valve testing, and to perform a control rod sequence exchange. The unit was returned to full power on November 22. Unit 1 was downpowered to approximately 75 percent on December 9 to facilitate main turbine valve testing. Full power was achieved later that day. On December 30, a planned downpower was performed to approximately 75 percent to facilitate main turbine valve testing. Power was returned to full later that day where it remained for the duration of the inspection period.

Unit 2

Unit 2 began the inspection period operating at full power. On October 20, a planned downpower to approximately 60 percent was performed to facilitate fuel leak suppression testing. After successfully suppressing the leaking fuel assembly, the unit was returned to full power on October 23. On November 1, Unit 2 was manually scrammed as a result of a loss of offsite power caused by a lockout of the startup auxiliary transformer due to a bus fault. As a result, an Unusual Event was declared due to the inability to power either 4kV emergency bus from offsite power. The Unusual Event was exited on November 2 when power was restored to the emergency buses by back feeding through the Unit 2 unit auxiliary transformer. Unit 2 was placed in Mode 4 (Cold Shutdown) while repairs were implemented to the startup transformer bus and to EDG #1 which tripped on low lubricating oil pressure during the event and was found to have a damaged engine crankshaft bearing. Following repairs, Unit 2 was placed in Mode 2 (Startup) on November 11. However, the unit was manually scrammed later during the startup due to rising condensate conductivity caused by condenser tube plugs that had become dislodged during or after the November 1 loss of offsite power event. Following repairs to the main condenser, a reactor startup was commenced on November 17 and Unit 2 entered Mode 1 (Power Operation) on November 18. Full power was achieved on November 24. An unplanned downpower was performed to approximately 32 percent on December 24 to remove the A recirculation pump from operation due to indications of a degraded pump shaft seal. Following entering single loop operation, power was increased to approximately 65 percent. On December 25, Unit 2 automatically scrammed due to actuation of the neutron monitoring system oscillation power range monitor trip. Unit 2 was placed in Mode 4 (Cold Shutdown) to facilitate repairs to the A recirculation pump shaft seal. Unit 2 was placed in Mode 2 (Startup) on December 29 and Mode 1 (Power Operation) on December 30. At the end of the inspection period, Unit 2 was 87 percent power and in the process of raising power to full.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors assessed the effectiveness of the licensee's cold weather protection program as it related to ensuring that the facility's service water pumps, emergency diesel generators, and condensate storage tank low level switches would remain functional and available in cold weather conditions. In addition to reviewing the licensee's program-related documents and procedures, walkdowns were conducted of the freeze protection equipment (e.g., heat tracing, area space heaters, etc.) associated with the above systems/components. Licensee problem identification and resolution associated with cold weather protections was also assessed. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial System Walkdowns

a. Inspection Scope

The inspectors performed three partial walkdowns of the below listed systems to verify that the systems were correctly aligned while the redundant train or system was inoperable or out-of-service (OOS) or, for single train risk significant systems, while the system was available in a standby condition. The inspectors assessed conditions such as equipment alignment (i.e., valve positions, damper positions, and breaker alignment) and system operational readiness (i.e., control power and permissive status) that could affect operability. The inspectors verified that the licensee identified and resolved equipment alignment problems that could cause initiating events or impact mitigating system availability. The inspectors reviewed Administrative Procedure ADM-NGGC-0106, Configuration Management Program Implementation, to verify that available structures, systems or components (SSCs) met the requirements of the configuration control program. Documents reviewed are listed in the Attachment.

- EDG #3 during start time testing on EDG #4 on October 12, 2006
- EDG #1 with EDG #2, OOS due to crack on exhaust expansion bellows on October 30, 2006
- Unit 2 high pressure coolant injection system while in operation during Unit 2 loss of offsite power event on November 1-2, 2006

To assess the licensee's ability to identify and correct problems, the inspectors reviewed the following Action Requests (ARs):

- AR 208508, Unit 2 service water vital header supply valve (2-SW-V177) handwheel separated from operator during testing
- AR 209265, Water found in Unit 2 high pressure coolant injection exhaust diaphragm pressure switch sensing lines
- AR 215467, Unit 2 high pressure coolant injection discharge piping snubber (2-E41-61SS99) found in an inoperable condition

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors conducted a detailed review of the alignment and condition of the emergency diesel generator system. The inspector reviewed the Updated Final Safety Analysis Report, associated attachments of Operating Procedure 0OP-39, Diesel Generator Operating Procedure, and the system diagrams (drawing numbers F-09348, LL-9112, and F-03161) in determining correct system lineup. The inspectors also reviewed maintenance history of the system.

To assess the licensee's identification and resolutions of problems, the inspectors reviewed the following:

- AR 210689, EDG #1 jacket cooling water temperature control valve controlling outside normal band
- AR 208626, EDG #3 start time approached 10 seconds
- AR 208599, EDG #3 declared inoperable due to handwheel and shaft separating from operator on the Unit 1 service water supply to jacket water heat exchanger supply valve (2-SW-V681)

b. Findings

No findings of significance were identified.

1R05 Fire Protection

.1 Fire Area Walkdowns

a. Inspection Scope

The inspectors reviewed ARs and work orders (WOs) associated with the fire suppression system to confirm that their disposition was in accordance with Procedure 0AP-033, Fire Protection Program Manual. The inspectors reviewed the status of ongoing surveillance activities to verify that they were current to support the operability of the fire protection system. In addition, the inspectors observed the fire suppression and detection equipment to determine whether any conditions or deficiencies existed which would impair the operability of that equipment. The inspectors toured the following seven areas important to reactor safety and reviewed the associated prefire plans to verify that the requirements for fire protection design features, fire area boundaries, and combustible loading were met. Documents reviewed are listed in the Attachment.

- Diesel generator cells 1-4, 23' elevation (4 areas)
- Emergency diesel generator building basement, 2' elevation (1 area)
- Service water building, 20' elevation (1 area)
- Unit 1 high pressure coolant injection room, -17 elevation (1 area)

b. Findings

No findings of significance were identified.

.2 Fire Drill

a. Inspection Scope

On October 18, 2006, the inspectors observed a plant fire drill in an emergency electrical distribution center (E8) located in the Emergency Diesel Generator Building, to assess the fire brigade performance and to verify that proper firefighting techniques for the type of fire encountered were utilized. The inspectors monitored the fire brigade's use of protective equipment and firefighting equipment to verify that preplanned firefighting procedures and appropriate firefighting techniques were used, and to verify that the directions of the fire brigade leader were thorough, clear, and effective. The inspectors attended the critique to confirm that appropriate feedback on performance was provided to brigade members and to ensure that areas for improvement were properly identified for licensee follow-up. In preparing for and evaluating the drill the inspectors reviewed the preplanned drill scenario, Brunswick Nuclear Plant Drill Scenario Guide, 99-F-DG-02, Fire in the E-8 Switchgear, Revision 2, and the associated prefire plan the area, 0PFP-DG, E8 Switchgear Room.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed the licensee's internal flooding analysis as described in Updated Final Safety Analysis Report (UFSAR) Section 3.4.2, Protection From Internal Flooding. Due to the risk significance of equipment in the Service Water and Emergency Diesel Generator Buildings, the inspectors reviewed UFSAR Section 3.4.2 analysis of the effects of postulated piping failures for these two areas to determine if the analysis assumptions and conclusions were based on the current plant configuration. The internal flooding design features and equipment for coping with internal flooding was inspected for the equipment located in these buildings. The walkdown included sources of flooding and drainage, sump pumps, level switches, watertight doors, curbs, pedestals and equipment mounting. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 External Flooding

a. Inspection Scope

The inspectors reviewed the licensee's external flooding analysis as described in UFSAR Section 3.4.1, Protection from External Flooding, to determine the external flood control design features. Walkdowns were conducted to inspect the external flood protection barriers including watertight doors, curbs, sealing of external building penetrations below flood line, and the sump pumps and level alarm circuits. Areas reviewed included the Emergency Diesel Generator Building, Fire Pump Building, the Service Water Building, and the Units 1 and 2 Reactor Building. The inspector reviewed the procedures for coping with external flooding contained in Abnormal Operating Procedure (AOP) 0AOP-13.0, Operation During Hurricane, Flood Conditions, Tornado, or Earthquake. Other documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R07 Annual Heat Sink Performance

a. Inspection Scope

The inspectors reviewed activities associated with the inspection and cleaning of the EDG #1 jacket cooling water heat exchanger per WO 649327 and Maintenance Surveillance Test 0MST-DG501R3, Emergency Diesel Generator 72-Month Inspection. The inspectors observed the results of the inspection conducted in accordance with preventive maintenance procedures. The inspection results were analyzed to determine if inspection frequencies were adequate to detect degradation prior to loss of heat removal capability below design-basis values

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Quarterly Review

a. Inspection Scope

The inspectors observed licensed operator performance and reviewed the associated training documents during annual dynamic simulator examination sessions for training cycle 2006-06. The simulator observations and review included evaluations of emergency operating procedure and abnormal operating procedure utilization. The inspectors reviewed Procedure 0TPP-200, Licensed Operator Continuing Training Program, to verify that the program ensures safe power plant operation. Two simulator examinations (different crews) were observed on November 28, 2006. The scenarios tested the operators' ability to respond to various instrumentation failures, abnormal operating transients, and accidents. The inspectors reviewed operator activities to verify consistent clarity and formality of communication, conservative decision-making by the crew, appropriate use of procedures, and proper alarm response. Group dynamics and supervisory oversight, including the ability to properly identify and implement appropriate Technical Specification (TS) actions, regulatory reports, and notifications, were observed. The inspectors observed instructor critiques and preliminary grading of the operating crews and assessed whether appropriate feedback was planned to be provided to the licensed operators. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Biennial Review

a. Inspection Scope

The inspectors reviewed facility operating history and associated documents in preparation for this inspection. While onsite the inspectors reviewed documentation, interviewed licensee personnel, and observed the administration of simulator operating tests associated with the licensee's operator requalification program. Each of the activities performed by the inspectors was done to assess the effectiveness of the licensee in implementing requalification requirements identified in 10 CFR 55, "Operators' Licenses." The evaluations were also performed to determine if the licensee effectively implemented operator requalification guidelines as established by their Systems Approach to Training (SAT) based program. The inspectors also reviewed and evaluated the licensee's simulation facility for adequacy for use in operator licensing examinations. The inspectors observed two crews during the performance of the operating tests. Documentation reviewed included written examinations, Job Performance Measures (JPMs), simulator scenarios, licensee procedures, on-shift records, simulator modification request records and performance test records, the feedback process, licensed operator qualification records, remediation plans, watchstanding, and medical records. Documents reviewed during the inspection are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.3 Annual Review of Licensee Requalification Examination Results.

On December 13, 2006, the licensee completed the requalification annual operating tests, required to be given to all licensed operators by 10 CFR 55.59(a)(2). The inspectors performed an in-office review of the overall pass/fail results of the individual operating tests, and the crew simulator operating tests. These results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

For the two equipment issues described in the ARs listed below, the inspectors reviewed the licensee's implementation of the Maintenance Rule (10 CFR 50.65) with respect to the characterization of failures, the appropriateness of the associated Maintenance Rule a(1) or a(2) classification, and the appropriateness of the associated a(1) goals and corrective actions. The inspectors reviewed the work controls and work practices associated with the degraded performance or condition to verify that they were appropriate and did not contribute to the issue. The inspectors also reviewed operations logs and licensee event reports to verify unavailability times of components and systems, if applicable. Licensee performance was evaluated against the requirements of Procedure ADM-NGGC-0101, Maintenance Rule Program.

- AR 211236, Trip of EDG#1, while in operation during Unit 2 loss of offsite power event on November 1-2, 2006
- AR 215809, Instrument air isolation valve (1-C11-116) to hydraulic control unit 14-15 was closed during maintenance

b. Findings

.1 Trip of EDG #1

On November 1, 2006 at 1823 Unit 2 was manually scrammed as a result of a loss of offsite power caused by a lockout of the Startup Auxiliary Transformer. EDGs #3 and #4 automatically started and re-energized emergency buses E3 and E4 which were affected by the loss of offsite power. EDGs #1 and #2 also automatically started but did not tie to their respective buses (E1 and E2) as the buses remained powered from the Unit 1 Unit Auxiliary Transformer. At approximately 0400 on November 2, EDG #1 tripped on low lubricating oil pressure. Prior to the EDG tripping, high lubricating oil strainer differential pressure alarms were received on both filter elements of the system's duplex strainer. Maintenance personnel dispatched to clean one of the strainers found that the high differential pressure was caused by clogging by fibrous lint material. EDG #1 tripped when operators were shifting lubricating system flow to a newly cleaned strainer.

The licensee found that the strainer filter elements also contained engine bearing material along with the fibrous lint material. Corrective maintenance on EDG #1 later found the engine's #9 main crankshaft bearing had failed. The licensee's failure analysis concluded that the bearing lost effective lubrication and the surface of the bearing was wiped. Inspections performed discovered a cleaning towel, that was apparently used during a recent maintenance outage which was completed on October 30, 2006, in the suction strainer of the engine-driven lubricating oil pump. Following repairs, the licensee declared EDG #1 operable on November 8.

This issue has been entered into the licensee's Corrective Action Program (CAP) as AR 211236. Pending further determination of the circumstances surrounding the trip of EDG #1 and the failure of crankshaft bearing #9, this issue is identified as URI 05000325,324/2006005-01, Trip of EDG #1 and Failure of Engine Crankshaft Bearing.

.2 Valve 1-C11-116 Closed During Maintenance

Introduction.

A self-revealing Green finding and NCV of Technical Specification 5.4.1, was identified for failure to follow work management process procedures while performing work on the Unit 1 control rod drive system.

Description.

On December 8, 2006, Unit 1 control rod 14-15 unexpectedly scrammed into the core. Control room operators entered the Abnormal Operating Procedure 2, Control Rod Malfunction/Misposition, and stabilized plant conditions. Although the initial power change as a result of the unexpected control rod insertion was approximately 2 percent, the event challenged operators. In order to recover the control rod to the correct position in the core, power was required to be lowered to approximately 93 percent.

Review of activities being performed at the time of the event revealed that maintenance was being performed on the control rod drive hydraulic control unit (HCU) instrument air system per WO 819565, Perform Leak Check Hydraulic Control Unit/Scram Discharge Volume Instrument Air. The task instructions of the work order instructed maintenance personnel to assist Operations and Engineering with identification of instrument air leakage. Specifically, the instructions of the work order stated "Walk with engineer and document leaks. Initiate work request as needed."

During the performance of the work, engineering and maintenance personnel discovered an air leak from the packing of isolation valve 1-C11-116, a one-quarter turn valve, associated with control rod HCU 14-15. Personnel involved with the work made the decision to perform repairs to the valve (i.e., tighten the valve's packing) using the minor maintenance process. During the process of tightening the packing nut, the valve stem moved in the closed direction. As a result, a loss of air to HCU 14-15 occurred which caused the scram isolation valves to open and scrammed control rod 14-15.

The licensee convened a Human Performance Review Board on the event. The licensee concluded that the mechanic and supervisor associated with the work did not fully understand or question the impact of the work, they did not notify Operations of the scope of work to be performed, nor did they seek senior reactor operator approval for performing the minor maintenance as required by ADM-NGGC-0104, Work Management Process, for work on safety-related or risk significant equipment.

Analysis.

The failure to follow the work management process by not obtaining senior reactor operator approval prior to performing valve packing adjustments on control rod drive system components (i.e., safety-related and/or risk-significant equipment) is a performance deficiency and resulted in an unexpected reactivity event and a challenge to plant operators. The finding was more than minor because it is associated with equipment performance and affected the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. The finding was assessed using the Significance Determination Process for Reactor Inspection Findings for At-Power Situations and was determined to be of very low safety significance (Green) because it did not contribute to both the likelihood of a reactor trip and the likelihood that mitigating equipment or functions would not be available. This finding had a crosscutting aspect of Human Performance because the control of the work did not keep operations personnel apprised of work status or the potential operational impact of the work activities. This finding is in the licensee's CAP as AR 215809.

Enforcement.

Technical Specification 5.4.1, Administrative Controls (Procedures), requires that written procedures shall be implemented covering applicable procedures recommended in Regulatory Guide 1.33, Appendix A, November 1972. Regulatory Guide 1.33 requires written procedures for the control of maintenance and for the method for obtaining permission for personnel to work. Nuclear Generation Group Standard Procedure ADM-NGGC-0104, Work Management Process, Revision 29, Step 9.7.5 requires senior reactor operator approval prior to performing minor maintenance work on safety-related or risk-significant equipment. Contrary to ADM-NGGC-0104, on December 8, 2006, a valve packing adjustment, considered minor maintenance, was performed on Unit 1 instrument air isolation valve 1-C11-116 for control rod HCU 14-15 without obtaining senior reactor operator approval of the maintenance. As a result, a reactivity event challenged control room operators when the associated control rod scrammed due to a loss of air to the control rod hydraulic control unit, a safety-related component, due to the valve being inadvertently closed during the maintenance. Because the finding is of very low safety significance and has been entered into the CAP (AR 215809), this finding is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy: NCV 05000325/2006005-02, Failure to Follow Work Management Process.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's implementation of 10 CFR 50.65 (a)(4) requirements during scheduled and emergent maintenance activities, using Procedure 0AP-025, BNP Integrated Scheduling and Technical Requirements Manual 5.5.13, Configuration Risk Management Program. The inspectors reviewed the effectiveness of risk assessments performed due to changes in plant configuration for maintenance activities (planned and emergent). The review was conducted to verify that, upon unforseen situations, the licensee had taken the necessary steps to plan and control the resultant emergent work activities. The inspectors reviewed the applicable plant risk profiles, work week schedules, and maintenance WO's for the following six conditions:

- WO 649327, Unit 1 elevated (yellow) risk due to EDG#1 planned maintenance outage from October 23-26 (planned)
- WO 793101, Unit 2 nuclear service water pumps A and B OOS due to service water bay cleaning on October 19, 2006 (planned)
- AR 210777, EDG#2 inoperable due to engine exhaust bellows crack on October 30, 2006 (emergent)
- AR 210717, EDG #1 unavailable on October 28, 2006, due to failed electrical components in manual voltage regulator (emergent)
- AR 214164, Unit 1 main turbine valve stroking due to various anomalies during testing on November 19-20, 2006 (emergent)
- AR 211212, Unit 2 in elevated risk condition (yellow) due to lockout of Unit 2 startup auxiliary transformer and trip of EDG#1 (emergent)

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the operability evaluations associated with the six issues documented in the ARs listed below, which affected risk significant systems or components, to assess, as appropriate: 1) the technical adequacy of the evaluations; 2) the justification of continued system operability; 3) any existing degraded conditions used as compensatory measures; 4) the adequacy of any compensatory measures in place, including their intended use and control; and 5) where continued operability was considered unjustified, the impact on any TS limiting condition for operation and the risk significance. In addition to the reviews, discussions were conducted with the applicable system engineer regarding the ability of the system to perform its intended safety function.

- AR 200002, Operability of Service Water Pumps with Associated Strainer Backwash Nonfunctional
- AR 211210, Unit 2 control room emergency ventilation system and alternate rod insertion did not automatically start/initiate following reactor scram on November 1, 2006
- AR 211377, EDG #4 exciter brushes sparking while operating during the Unit 2 loss of offsite power event on November 1-2, 2006
- AR 211380, Unit 2 high pressure coolant injection system pump outboard seal leak while operating during the Unit 2 loss of offsite power event on November 1-2, 2006

- AR 208746, Unit 1 B conventional service water pump motor stator exceeded 311°F during operation
- AR 213838, Cracked mounting bushing on EDG #4 inner collector ring stud

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

For the seven maintenance activities listed below, the inspectors reviewed the post-maintenance test procedure and witnessed the testing and/or reviewed test records to confirm that the scope of testing adequately verified that the work performed was correctly completed,. The inspectors verified that the test demonstrated that the affected equipment was capable of performing its intended function and was operable in accordance with TS requirements. The inspectors reviewed the licensee's actions against the requirements in Procedure 0PLP-20, Post Maintenance Testing Program.

- WO 964144, Unit 2 main turbine bypass valve #9 operation not smooth
- WO 649327, EDG #1 Maintenance Surveillance Test 0MST-DG501R3, Emergency Diesel Generator 72-month Inspection
- WO 974337, EDG #1 crankshaft bearing #9 repairs
- AR 211218, Unit 2 safety/relief valve self-closed after being manually actuated to control pressure during Unit 2 loss of offsite power event on November 1-2, 2006
- WO 977206, Degraded valve yoke sleeve on Unit 2 A residual heat removal pump minimum flow manual isolation valve (2-E11-F018A)
- WO 985797, Implement changes to number of confirmation counts for the confirmation density alarm and trip functions of the oscillation power range monitors
- WO 995793, EDG#1 engine right starting air header pressure reducing valve repairs

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 2 Forced Outage B217F3

a. Inspection Scope

The inspectors evaluated the Unit 2 Forced Outage B217F3 which commenced on November 1, 2006, following a loss of offsite power event due to lockout of the startup auxiliary transformer. The unit entered Mode 4 (Cold Shutdown) on November 4. Following repairs to Unit 2 startup auxiliary transformer, Unit 2 entered Mode 2 (Startup) and achieved criticality on November 11. During plant heatup activities later that day, operators manually scrammed the reactor due to high condensate conductivity caused by dislodged condenser tube plugs. The unit entered Mode 4 (Cold Shutdown on November 12. Mode 2 (Startup) was entered on November 17 following repairs to the main condenser. Mode 1 (Power Operation) was entered on November 18 and full power was achieved on November 24. Documents reviewed are listed in the Attachment. The following specific areas were reviewed during the inspection period:

Outage Plan. The inspectors reviewed the outage plan to verify that the licensee had considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth.

Shutdown and Cooldown. The inspectors responded to the control room following the scram on November 1 and observed operator recovery actions. Portions of the Unit 2 cooldown to enter the outage were observed to verify that activities were in accordance with plant procedures. The inspectors verified that the licensee monitored cooldown restrictions by performing 2PT-01.7, Heatup/Cooldown Monitoring, to assure that TS cooldown restrictions were satisfied.

Licensee Control of Outage Activities. The inspectors observed and reviewed activities and plant conditions to verify that the licensee maintained defense-in-depth commensurate with the outage risk control plan. The inspectors reviewed the following specific items, as specified:

- Decay Heat Removal. The inspectors reviewed decay heat removal procedures and observed decay heat removal systems' parameters to verify proper removal of decay heat. The inspectors conducted main control room panel walkdowns and walked down portions of the systems in the plant to verify system availability.
- Reactivity Control. The inspectors observed licensee performance during the outage to verify that reactivity control was conducted in accordance with procedures and TS requirements.
- Electrical Power. The inspectors reviewed the following licensee activities related to electrical power during the outage to verify that they were in accordance with the outage risk plan:

- Controls over electrical power systems and components to ensure emergency power was available
- Controls and monitoring of electrical power systems and components and work activities in the power transmission yard

Monitoring of Heatup and Startup Activities. The inspectors reviewed to verify, on a sampling basis, that TS, license conditions, and other requirements for mode changes were met prior to changing modes or plant configurations.

Identification and Resolution of Problems. The inspectors reviewed ARs to verify that the licensee was identifying problems related to outage activities at an appropriate threshold and entering them in the corrective action program. The inspectors reviewed the following issues identified during the outage to verify that the appropriate corrective actions were implemented or planned:

- AR 211211, Alternate rod insertion did not actuate during scram transient
- AR 211210, Control room emergency ventilation did not actuate during scram transient
- AR 211218, Safety/relief valve F closed at 900 psig without any action
- AR 211269, Cooldown rate exceeded Technical Specification limit
- AR 211233, Iodine spike in turbine building following scram
- AR 211212, Unit 2 startup auxiliary transformer lockout on bus fault
- AR 212651, High pressure coolant injection pump shaft seal leak during operation

b. Findings

No findings of significance were identified.

.2 Unit 2 Forced Outage B217F4

a. Inspection Scope

The inspectors evaluated the Unit 2 Forced Outage B217F4 which commenced on December 25, 2006, following an automatic scram due to the oscillation power range monitoring system detecting core power instability while in single recirculation loop operation. Unit 2 proceeded to Mode 4 (Cold Shutdown) to facilitate repairs to the A recirculation pump seal which demonstrated degraded conditions of the first and second stage seal elements. Mode 2 (Startup) was entered on December 29 and Mode 1 (Power Operation) was entered on December 30. Documents reviewed are listed in the Attachment. The following specific areas were reviewed during the inspection period:

Outage Plan. The inspectors reviewed the outage plan to verify that the licensee had considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth.

Shutdown and Cooldown. The inspectors responded to the control room following the scram on December 25 and observed operator recovery actions. The inspector observed portions of the cooldown to enter the outage to verify that activities were in accordance with plant procedures.

Licensee Control of Outage Activities. The inspectors observed and reviewed activities and plant conditions to verify that the licensee maintained defense-in-depth commensurate with the outage risk control plan. The inspectors reviewed decay heat removal procedures and observed decay heat removal systems' parameters to verify proper removal of decay heat. The inspectors reviewed the electric power systems to ensure emergency power was available.

Monitoring of Heatup and Startup Activities. The inspectors reviewed to verify, on a sampling basis, that TS, license conditions, and other requirements for mode changes were met prior to changing modes or plant configurations.

Identification and Resolution of Problems. The inspectors reviewed ARs to verify that the licensee was identifying problems related to outage activities at an appropriate threshold and entering them in the corrective action program. The inspectors reviewed the following issues identified during the outage to verify that the appropriate corrective actions were implemented or planned:

- AR 217345, Post scram investigation report
- AR 215053, Recirculation pump seal leak

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

.1 Routine Surveillance Testing

a. Inspection Scope

The inspectors either observed surveillance tests or reviewed test data for the four risk significant SSC surveillances, listed below, to verify the tests met TS surveillance requirements, UFSAR commitments, in-service testing (IST) requirments, and licensee procedural requirements. The inspectors assessed the effectiveness of the tests in demonstrating that the SSCs were operationally capable of performing their intended safety functions.

- 0MST-HPCI 23Q, High Pressure Coolant Injection System Turbine Exhaust Diaphragm High Pressure Instrument Channel Calibration, performed on Unit 2 on October 13, 2006
- 2MST-PCIS21R, Primary Containment Isolation System Reactor LL2 and LL3 Division 1 Instrument Channel Calibration and Functional Test, performed on November 5, 2006

- 2MST-PCIS29R, Primary Containment Isolation System Reactor Water LL2 and LL3 Division 2 Instrument Channel Calibrator and Functional Test, performed on November 6, 2006
- 2OI-03.2, Control Operator Daily Surveillance Report (including drywell leakage rate determination), performed the week of November 10, 2006

b. Findings

No findings of significance were identified.

.2 In-service Surveillance Testing

a. Inspection Scope

The inspectors reviewed the performance of Periodic Test 2PT-24.1-2, Service Water Pump and Discharge Valve Operability Test, performed on Unit 2 A conventional service water pump on November 24, 2006. The inspectors evaluated the effectiveness of the licensee's American Society of Mechanical Engineers (ASME) Section XI testing program to determine equipment availability and reliability. The inspectors evaluated selected portions of the following areas: 1) testing procedures; 2) acceptance criteria; 3) testing methods; 4) compliance with the licensee's IST program, TS, selected licensee commitments, and code requirements; 5) range and accuracy of test instruments; and 6) required corrective actions. The inspectors also assessed any applicable corrective actions taken.

To assess the licensee's ability to identify and correct problems, the inspector reviewed AR 214876 which documented that the Unit 1 A conventional service water pump was discovered to be in the Alert range following testing on November 30, 2006.

b. Findings

Introduction.

An NRC-identified Green finding and NCV 10CFR50, Appendix B, Criteria XII, Control of Measure and Test Equipment, was identified for failure to calibrate and adjust service water pressure gages used to collect ASME Section XI in-service test data.

Description.

During plant status review of operator logs, the inspectors noted that one of the conventional service water pump discharge pressure gages was found to be reading 56.5 psig vice 0 psig following securing of the pump after completing ASME Section XI in-service testing. Periodic Test 2PT-24.1-2, Service Water Pump and Discharge Valve Operability Test, Revision 51, implements ASME Section XI in-service testing of the sites four nuclear and six conventional service water pumps as required by TS 5.5.6, In-service Testing Program. Following the performance of 2PT-24.1-2 on November 24, 2006, operators logged that the Unit 2 A conventional service water pump discharge pressure gage (2-SW-PI-122) was apparently sticking. This was because the gage continued to indicate pressure following the shutdown of the pump. Operators generated a work request to correct the problem. No other corrective actions were taken at that time.

Inspector review of the completed test procedure showed that each of the nuclear and conventional service water pump's discharge pressure gage was used to collect the associated pumps' test data. This data is used in the calculation of developed pump head as required by ASME Section XI. The inspector questioned the calibration frequency of the service water pump discharge pressure gages.

The licensee informed the inspector that the preventive maintenance work task that calibrated the service water pump discharge pressure gages was canceled in 2001. The calibration frequency was previously established as every two years. The preventive maintenance revision request which canceled the periodic calibration (PER 6565) stated that the gages were used for information and did not perform automatic functions as the basis for the change. Review of work history showed that none of the gages have been calibrated within the previously established two year frequency and the licensee entered TS Surveillance Requirement 3.0.3 for a missed surveillance and the licensee entered the issue into the CAP as AR 214841 and AR 214843. In-service testing on the site's service water pumps, with the use of portable calibrated test equipment to measure discharge pressure, was completed on November 30, 2006. The test results revealed that the Unit 1 A conventional service water pump was in the ASME Section XI Alert range, based on developed differential pressure. This required the pump to be tested on an increased frequency.

Analysis.

The failure to perform periodic calibrations on the site's service water pump discharge pressure gages, used in the collection of ASME Section XI in-service test data to demonstrate service water pump TS operability, is a performance deficiency. Periodic calibrations are required to maintain gage accuracy within necessary limits. The finding was more than minor because it was associated with service water pump equipment performance and affected the Mitigating System Cornerstone objective to ensure the capability of system that respond to initiating events to prevent undesirable consequences. In addition, if left uncorrected the finding could potentially become a more significant safety concern because the issue affected all the site's service water pumps and degraded pump performance could go undetected. The finding was assessed using the Significance Determination Process for Reactor Inspection Findings for At-Power Situations and was determined to be of very low safety significance (Green) because it did not result in the loss of safety function of a service water pump. This finding is in the licensee's CAP as AR 214841 and AR 214843.

Enforcement.

10CFR50, Appendix B, Criteria XII, Control of Measuring and Test Equipment, requires, in part, that measures shall be established to assure that gages used in activities affecting quality are properly calibrated and adjusted at specified periods to maintain accuracy within necessary limits.

Contrary to the above, Units 1 and 2 service water pump discharge pressure gages used to collect ASME Section XI in-service test data to demonstrate service water pump operability, an activity affecting quality, were not calibrated and adjusted at specified periods to maintain accuracy. This condition existed from October 2001, when the preventive maintenance work task to performed the calibration were canceled, until November 30, 2006. The finding is of very low safety significance and has been entered into the CAP (AR 214841 and AR 214843), and is being treated as an NCV, consistent with Section VI.A of the Enforcement Policy: NCV 05000325, 324/2006005-03, Failure to Periodically Calibrate Service Water Pump Discharge Pressure Gages.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Operating Manual 0PLP-22, Temporary Changes, to assess the implementation of Engineering Change (EC) 65356, Removal of Manual Voltage Regulator Circuit for EDG #1, which was implemented on October 29, 2006. The inspectors reviewed the EC to verify that the modification did not affect the functional capability of the EDG, that the modification was properly installed, and appropriate post-installation testing was performed.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee submittals for the Units 1 and 2 performance indicators (PIs) listed below for the period October 2004 through September 2006. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, “Regulatory Assessment Performance Indicator Guideline”, Revision 4, were used to confirm the reporting basis for each data element.

Reactor Safety Cornerstone

- Reactor Coolant System Activity
- Reactor Coolant System Leakage

A sample of plant records and data was reviewed and compared to the reported data to verify the accuracy of the PIs. The licensee's corrective action program records were also reviewed to determine if any problems with the collection of PI data had occurred. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Routine Review of ARs

To aid in the identification of repetitive equipment failures or specific human performance issues for followup, the inspectors performed frequent screenings of items entered into the licensee's CAP. The review was accomplished by reviewing daily ARs.

.2 Annual Sample Review

a. Inspection Scope

The inspectors performed an in-depth annual sample review of plant operator workarounds as documented in licensee's operator workaround program and corrective action documents. This review was performed to verify that the licensee identified operator workarounds at an appropriate threshold, entered the issues into the CAP, and planned or implemented appropriate corrective actions. The inspectors reviewed the actions taken to verify that the licensee had adequately addressed the following attributes:

- Complete, accurate, and timely identification of the problem
- Evaluation and disposition of operability and reportability issues
- Consideration of previous failures, extent of condition, generic or common cause implications
- Prioritization and resolution of the issue commensurate with the safety significance
- Identification of the root cause and contributing causes of the problem
- Identification and implementation of corrective actions commensurate with the safety significance of the issue

b. Findings and Observations

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The review was focused on repetitive equipment issues but also considered the results of frequent inspector CAP item screening (discussed above), licensee trending efforts, and licensee human performance results. The review considered the period of July through December 2006. The review further included issues documented outside the normal CAP in major equipment lists, repetitive and/or rework maintenance lists, operational focus list, control room deficiency list, outstanding work order list, quality assurance audit/surveillance reports, key performance indicators, and self-assessment reports. The inspectors compared and contrasted their results with the results contained in the Brunswick Plant CAP Rollup and Trend Analysis report for the 3rd quarter 2006. Corrective actions associated with a sample of the issues identified in the licensee's trend reports were reviewed for adequacy. The inspectors also evaluated the reports against the requirements of the licensee's CAP as specified in Nuclear Generation Group Standard Procedure CAP-NGGC-0200, Corrective Action Program, and 10 CFR 50, Appendix B.

b. Assessment and Observations

No findings of significance were identified. The inspectors noted a trend in personnel not following site process procedures. This was exemplified by the following NRC-identified and self-revealing issues: 1) EDG test equipment left installed following troubleshooting without entering the temporary modification process (AR 209244); 2) Drain rig installed on Unit 2 high pressure coolant injection pump seal leakoff drain without entering the temporary modification process (AR 212651); 3) Procedure steps for replacing the EDG #1 crankshaft bearing #9 were omitted without entering the procedure change process (AR 212166); and 4) Minor maintenance was performed on a control rod drive instrument air valve without informing a senior reactor operator contrary to the work control process as documented in Section 1R12.2 (AR 215809). The inspectors determined that the NRC identified issues, listed as examples 1 through 3 above, are issues which constitute violations of minor significance that are not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy.

The inspectors noted a declining trend associated with EDG reliability over the review period. With the reporting of Mitigating System Performance Index (MSPI) data following the second quarter 2006, the MSPI for EDGs was White primarily due to unreliability. During the review period, the inspectors noted an additional EDG failure, as discussed in Section 1R12.1, which will contribute to the MSPI. Other issues associated with the EDGs that, although they may or may not contribute to MSPI, indicate issues with effectiveness of corrective actions and/or preventive maintenance. These are exemplified by the following issues associated with the site's EDG, all of which occurred in the 4th quarter 2006: 1) EDG #2 exhaust bellows crack (AR 210777); 2) EDG #1 jacket cooling water temperature control valve operating problems (AR

210689); 3) Water contamination in the oil of EDG #2 air compressor #2 and EDG #4 air compressor #1 (AR 205259); 4) EDG #3 exciter capacitors leaking electrolytic fluid (AR 206119); 5) EDG #4 exciter brush excess sparking during operation (AR 211377); 6) EDGs #2 and #3 generator pedestal bearing high temperature alarms during operation (AR 211474); 7) EDG #1 right starting air header pressure control valve failure (AR 217492); and 8) Crack found in EDG #4 cell exhaust fan blade (AR 209445).

4OA3 Event Follow-up

.1 Personnel Performance during Plant Evolutions

a. Inspection Scope

The inspectors observed and/or reviewed the following abnormal plant condition and plant transient to assess operator performance during non-routine evolutions and events. Operator logs, plant computer data, and associated operator actions were reviewed as well as the appropriate procedures:

- Unit 2 entered Emergency Operating Procedure 0EOP-4-RCCP, Radiation Release Control Procedure, on October 10, 2006, due to main steam line radiation monitor D reading high
- Unit 2 manual reactor scram due to loss of offsite power caused by lockout of startup auxiliary transformer on November 1, 2006
- Unit 2 automatic reactor scram due to oscillation power range monitor trip on Growth Rate Algorithm on December 25, 2006

b. Findings

No findings of significance were identified.

.2 (Closed) Licensee Event Report (LER) 05000325/2006004 and Supplement 1: As-Found Values for Safety/Relief Valve Lift Setpoints Outside Technical Specification Allowed Tolerance.

The LER reported that as-found testing for four of the eleven safety/relief valves removed from Unit 1 during the Spring 2006 outage (i.e., B116R1) were outside the Technical Specification allowed setpoint tolerance. The cause of the failure of the valves was due to maintenance practices. The licensee has instituted corrective actions to preclude recurrence. The failure of these four safety/relief valves to lift within the allowed setpoint limits constituted a condition prohibited by TS 3.4.3. However, an evaluation of the as-found condition of the safety/relief valves was compared to the current overpressure analysis. The analysis concluded that the overpressure analysis remained bounding. The enforcement aspects of the violation are discussed in Section 4OA7 of this report. This LER is closed.

4OA5 Other Activities

.1 Review of Institute of Nuclear Power Operations (INPO) August 2006 Brunswick Review Visit Report

The inspectors reviewed the INPO August 2006 Brunswick Review Visit Report. The review determined that the results of the INPO report were generally consistent with the results of similar evaluations conducted by the NRC. The inspectors concluded that no additional Regional follow-up concerning this report was warranted.

4OA6 Meetings, Including Exit

Exit Meeting Summary

On January 19, 2006, the resident inspectors presented the inspection results to Mr. Scarola and other members of his staff. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which met the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for disposition as a non-cited violation (NCV).

- Technical Specification Limiting Condition for Operation 3.4.3, Safety/Relief Valves, requires 10 safety/relief valves to be operable while in Mode 1 with their lift setpoints within a specified range. Contrary to this, during surveillance testing on safety/relief valves removed from Unit 1 during the spring 2006 refueling outage (i.e., B116R1), four of the eleven valves actuated at pressures outside the specified band. This was identified in the licensee's CAP as AR 196332. This finding is of very low safety significance because the as-found lift setpoint conditions of the Unit 1 safety/relief valves were analyzed and determined to meet the design basis criteria for an over-pressurization event.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

G. Atkinson, Supervisor - Emergency Preparedness
L. Beller, Superintendent Operations Training
A. Brittain, Manager - Security
T. Cleary, Director - Site Operations
E. O'Neill, Manager - Training Manager
D. Griffith, Manager - Outage and Scheduling
L. Grzeck, Lead Engineer - Technical Support
S. Howard, Manager - Operations
R. Ivey, Manager - Site Support Services
T. Pearson, Supervisor - Operations Training
A. Pope, Supervisor - Licensing/Regulatory Programs
S. Rogers, Manager - Maintenance
J. Scarola, Site Vice President
T. Sherrill, Engineer - Technical Support
T. Trask, Manager - Engineering
J. Titrington, Manger - Nuclear Assessment Services
M. Turkal, Lead Engineer - Technical Support
M. Williams, Manager - Operations Support
B. Waldrep, Plant General Manager

NRC Personnel

Randall A. Musser, Chief, Reactor Projects Branch 4, Division of Reactor Projects Region II

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000325,324/2006005-01	URI	Trip of EDG #1 and Failure of Engine Crankshaft Bearing (Section 1R12.1)

Opened and Closed

05000325/2006005-02	NCV	Failure to Follow Work Management Process (Section 1R12.2)
05000325,324/2006005-03	NCV	Failure to Periodically Calibrate Service Water Pump Discharge Pressure Gages (Section 1R22.2)

Closed

05000325/2006004 and Supplement 1	LER	As-Found Values for Safety/Relief Valve Lift Setpoints Outside Technical Specification Allowed Tolerance (Section 4OA3.2)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Plant Operating Manual (POM), Volume VII, Operating Instruction 0OI-01.03, Non-Routine Activities
WO-751049, Check and Verify Operability of Unit 1 Heat Tracing System
WO-751050, Check and Verify Operability of Unit 2 Heat Tracing System
POM, Volume XII, Preventive Maintenance 0PM-HT001, Preventive Maintenance on Plant Freeze Protection and Heat Tracing System

Section 1R04: Equipment Alignment

POM, Volume III, Operating Procedure 2OP-39, High Pressure Coolant Injection System Operating Procedure
POM, Volume III, 0OP-39, Diesel Generator Operating Procedure
System Description SD-39, Emergency Diesel Generators

Section 1R05: Fire Protection

POM, Volume XIX, Prefire Plan 0PFP-DG, Diesel Generator Building Prefire Plans
POM, Volume XIX, Prefire Plan 0PFP-PBAA, Power Block Auxiliary Areas Prefire Plans
POM, Volume XIX, Prefire Plan 1PFP-RB, Unit 1 Reactor Building Prefire Plans

Section 1R06: Flood Protection Measures

POM, Volume XXI, Abnormal Operating Procedure (AOP) 0AOP-13.0, Operation During Hurricane, Flood Conditions, Tornado, or Earthquake
POM, Volume X, Periodic Test (PT) 0PT-34.2.2.1, Fire Door, ASSD Access/Egress Door, Severe Weather Door Inspections
Updated Final Safety Analysis Report Chapters 2 and 3

Section 1R20: Refueling and Other Outage Activities

POM, Volume IV, General Operating Procedure, 0GP-02, Approach to Criticality and Pressurization of the Reactor

POM, Volume IV, General Operating Procedure, 0GP-03, Unit Startup and Synchronization
POM, Volume IV, General Plant Operating Procedure, 0GP-05, Unit Shutdown
POM, Volume IV, General Plant Operating Procedure, 0GP-12, Power Changes
POM, Volume III, Operating Procedure, 2OP-17, Residual Heat Removal System Operating Procedure

Section 1R11: Licensed Operator Requalification

Procedures and Records

Training Administrative Procedure (TAP-412), Simulator Operation and Maintenance, Revision 0.
TAP-409, Conduct of Simulator Training and Evaluation, Revision 9.
SI 214.1, Simulator Instruction for Simulator Documentation, Revision 2.
TAP-411, Initial Licensing and Continuing Training Annual/Biennial Exam Development and Security, Revision 5.
Six remedial training records.
LOCT 2006 Student Feedback.
LOCT 2005 Cycle Training Student Feedback.
RO/SRO 2005 LOCT Annual Written Exam (Shifts A, B, C, D, and E)

2005 LOR Program Grades

Badge Access Transaction Reports for Reactivation of Licenses. (8)
Licensed Operator Medical Records. (15)
Human Performance Condition Reports. (10)

Job Performance Measures

LOT-SIM-JP-025-A02, Re-open MSIV's IAW OP-25, Revision 3.
LOT-SIM-JP-025-A03, Emergency Equalization Around MSIV's – Anticipate Emergency Depressurization, Revision 2.
LOT-SIM-JP-037-A06, Manual Startup of Control Building Emergency Ventilation – Trip of One Fan, Revision 1.
LOT-SIM-JP-300-K11, SEP-04 – Restart RB HVAC with Failure to Isolate, Revision 1.
AOT-OJT-JP-041-A02, Perform Actions Associated with Fire – Aligning the Fire Protection Alternate Water Supply, Revision 6.
AOT-OJT-JP-303-A01, Station Blackout: Crosstie of 4KV E-Buses, Revision 7.
AOT-OJT-JP-303-A11, Station Blackout: Crosstie of 4KV E-Buses (E2 – E4), Revision 0.
LOT-OJT-JP-300-K03, Defeat System Logic Per EOP-01-SEP-10 – Group 1 Low Level 3 Isolation Logic, Revision 2.
LOT-SIM-JP-019-A09, Transfer HPCI from Level to Pressure Control Using the Hard Card, Revision 1.
LOT-SIM-JP-003-A03, Transfer RPS Bus B from Normal to Alternate Power, Revision 2.
LOT-SIM-JP-050-B02, Manual transfer of Emergency Bus Supply from the EDG to the Normal Feeder, Revision 7.

LOT-SIM-JP-030-A02, Rapid Swap of Off-Gas Trains IAW 2OP-30, Revision 1.
LOT-SIM-JP-300-K17, Defeat RCIC Low Pressure Isolation Logic, Revision 1.
AOT-OJT-JP-300-J24, RCIC Injection Using Manual Valve Operation with Overspeed, Revision 0.
AOT-OJT-JP-302-G01, Loss of DC Power - Transfer of DC Control Power, Revision 2.

Scenarios

LORX-026, Loss of 2B NSW Pump, Loss of 2B NSW Pump, Loss of Off-Site Power, Failure of Diesels to Auto Start, Small Break LOCA, RCIC Failure in Automatic, ADS Logic Failure, 11/09/2006.
LORX-006, Loss of UPS, Turbine High Vibration, ATWS, Loss of power to EHC, 10/31/2006.
LORX-052, HCU Low Pressure, CSW Leak, EHC Pressure Regulator Failure, RPS Fails to Scram, Loss of 4KV Busses 2D and E3, Large Break LOCA, 10/18/2006.
LORX-051, MSL Rad Monitor B Fails Downscale, HDD Deaerator Level Control Failure, HPCI Steam Line Break with Failure to Isolate, Electrical ATWS, Emergency Depressurization Required, 10/16/2006.

Simulator Transient Tests

STP-OL-001, Simulator Operating Limits Test, 10/05/2006.
STP-RT-001, Simulator Real Time Test, 10/05/2006.
STP-RP-001, Simulator Repeatability Test, 10/05/2006.
STP-SS-002, 50% Power Steady State Comparison, 11/06/2006.
STP-SS-003, 75% Power Steady State Comparison, 11/06/2006.
STP-SS-004, 100% Power Steady State Comparison, 11/06/2006.
STP-TN-001, Manual Scram, 11/06/2006.
STP-TN-002, Simultaneous Trip All Feedwater Pumps, 11/06/2006.
STP-TN-003, Simultaneous Closure of All MSIV'S, 11/06/2006.
STP-TN-004, Simultaneous Trip of Both Recirculation Pumps, 11/06/2006.
STP-TN-005, Single Recirculation Pump Trip, 11/06/2006.
STP-TN-006, Turbine Trip (Does Not Result In An Immediate Reactor Scram), 11/06/2006.
STP-TN-006, Unit 1 Turbine Trip (Does Not Result In An Immediate Reactor Scram), 11/06/2006.
STP-TN-007, Maximum Rate Power Ramp – Recirc Flow Controller In Manual, 11/06/2006.
STP-TN-008, Design Basis LOCA In Conjunction With Loss Of Off-Site Power, 11/06/2006.
STP-TN-009, Maximum Size Unisolable Main Steam Line Rupture, 11/06/2006.
STP-TN-010, MSIV Closure With One Stuck Open Safety / Relief Valve and High Pressure ECCS Inhibited, 11/06/2006.
STP-TN-011, Inadvertent HPCI Initiation, 11/06/2006.

Simulator Change Request Documentation

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Section 1R23: Temporary Plant Modifications

Design Basis Document 39, Emergency Diesel Generator System DBD
System Description 39, Emergency Diesel Generators
Drawing 0-FP-82717, Unit 1 and Unit 2 Diesel Generator DC Regulator
AR 212307, EDG Manual Voltage Regulator G4 Capacitor Contamination